Effect on Electricity Prices. Nationally, the 8 million ton and 10 million ton reduction programs would raise average electricity prices between 1 percent and 5 percent, respectively, from projected 1995 levels under current policy (see Tables 7 and 8). But larger regional price changes could occur under these same emission reductions schemes. For example, electricity prices in West Virginia could rise as much as 31 percent over expected 1995 levels under the 8 million ton rollback case, and could more than triple under the 10 million ton rollback option. (A large percentage of these high increases represents the passthrough to consumers of significant amounts of capital costs in 1995, which would be incurred to meet the control program deadlines; as this debt is retired in the rate base, prices would fall in later years.) [13]

In contrast, electricity prices under either rollback plan could fall in some areas that would export power--such as North and South Dakota, Nevada, and New Mexico--since the power sold outside the state could subsidize power sold within the state. The electricity price model used in this study employs such an assumption in assigning costs. Actual power transactions across state borders, however, are subject to a myriad of pricing rules and such an assumption may not always hold.

Shifts in Coal Supply and Demand Patterns

Domestic coal production is expected to rise from its current level of around 883 million tons per year to about 1.13 billion tons annually by 1995. Requirements to control sulfur dioxide emissions from utilities should not affect these national projections but, depending on the nature of the regulation, they could affect regional output. A key anticipated trend is that, under all SO_2 reduction scenarios, coal production in the Midwest and Pennsylvania would fall, as demand shifts from high-sulfur coal to low-sulfur coal. This trend--which will occur to some extent even under current laws--could be mitigated but not reversed by limiting coal switching.

Assuming no change in current policy, the states of Ohio, Illinois, Indiana, and Pennsylvania could experience slightly lower coal production in 1995 compared with 1985--from 197 million tons to 192 million tons (see

13. The schedule of costs that are passed to consumers in electricity prices (shown in Tables 7 and 8) is somewhat different than the annual levelized costs for utilities (shown in Tables 5 and 6), which represent the annual average of annuitized capital and operating costs over the life of the program. Most electricity rate decisions allow capital costs to be recovered during the early years of a plant's economic life. Rates during this period are, therefore, higher than the average rates experienced over the life of the plant. Thus, the electricity prices shown in Tables 7 and 8 reflect actual first-year prices of the program, and are not based on average annual costs over the utility's lifetime.

TABLE 7. ELECTRICITY PRICE CHANGES AS OF 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case 1995	Option II-1A	Option II-1B	Percent Difference from 1995 Base Case: Option II-1A	Percent Difference from 1995 Base Case: Option II-1B
Alabama, Mississippi	46.6	46.9	47.1	0.8	1.1
Arizona	55.9	55.5	55.9	-0.6	0.1
Arkansas, Oklahoma, Louisiana	77.5	78.5	78.3	1.3	1.0
California	78.3	78.3	78.5	0.0	0.3
Carolinas, North and South	50.3	51.2	50.9	2.0	1.2
Colorado	57.4	57.6	60.6	0.3	5.6
Dakotas, North and South	32.1	31.4	31.6	-2.4	-1.6
Florida	75.2	76.0	75.7	1.2	0.7
Georgia	54.2	56.1	55.9	3.6	3.2
Idaho	43.0	43.3	43.2	0.6	0.5
Illinois	59.3	60.8	60.5	2.4	2.0
Indiana	53.9	55.0	55.0	2.1	2.0
Iowa	59.3	61.1	62.0	2.9	4.5
Kansas, Nebraska	57.9	58.1	58.2	0.3	0.6
Kentucky	55.0	55.9	55.5	1.7	0.9
Maine, Vermont, New Hampshire	80.9	80.4	80.6	-0.6	-0.4
Maryland, Delaware	66.4	67.6	68.3	1.9	2.9
Massachusetts, Connecticut, Rhode Island	80.6	83.0	83.1	3.0	3.2

(Continued)

TABLE 7. (Continued)

State	Base Case 1995	Option II-1A	Option II-1B	Percent Difference from 1995 Base Case: Option II-1A	Percent Difference from 1995 Base Case: Option II-1B
Michigan	57.7	58.4	58.2	1.2	1.0
Minnesota	54.2	54.4	55.1	0.5	1.8
Missouri	59.6	62.3	62.7	4.5	5.1
Montana	41.1	41.0	41.5	-0.4	1.0
Nevada	48.8	47.1	47.1	-3.6	-3.6
New Mexico	68.2	66.9	64.0	-1.9	-6.1
New York (Downstate), New Jersey	99.3	100.0	99.8	0.7	0.5
New York (Upstate)	53.1	53.7	53.6	1.0	0.8
Ohio	57.8	59.8	59.3	3.4	2.5
Pennsylvania	58.2	59.3	59.6	2.0	2.4
Tennessee	46.9	47.3	47.1	1.0	0.5
Texas	79.4	79.4	79.2	0.0	-0.3
Utah	39.0	44.7	44.6	14.6	14.4
Virginia, District of Columbia	58.7	60.0	59.9	2.2	1.9
Washington, Oregon	35.4	35.3	35.3	-0.3	-0.1
West Virginia	27.2	26.8	35.7	-1.6	31.2
Wisconsin	52.7	55.1	57.0	4.6	8.2
Wyoming	43.0	43.3	43.2	0.6	0.5
National Average	62.0	62.8	62.9	1.3	1.5

SOURCE: Congressional Budget Office.

TABLE 8. ELECTRICITY PRICE CHANGES AS OF 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case 1995	Option II-2A	Option II-2B	Percent Difference from 1995 Base Case: Option II-2A	Percent Difference from 1995 Base Case: Option II-2B
Alabama, Mississippi	46.6	45.6	43.2	-2.1	-7.3
Arizona	55.9	55.9	55.8	0.0	-0.1
Arkansas, Oklahoma, Louisiana	77.5	78.8	78.9	1.6	1.7
California	78.3	78.3	78.6	0.0	0.4
Carolinas, North and South	50.3	51.2	50.6	1.8	0.8
Colorado	57.4	57.7	61.3	0.6	6.8
Dakotas, North and South	32.1	30.4	30.5	-5.3	-5.2
Florida	75.2	75.9	75.3	1.0	0.2
Georgia	54.2	56.2	55.8	3.7	3.0
Idaho	43.0	43.5	43.3	1.0	0.6
Illinois	59.3	62.4	63.2	5.1	6.5
Indiana	53.9	55.5	59.8	3.0	10.9
Iowa	59.3	62.3	61.9	5.0	4.3
Kansas, Nebraska	57.9	58.4	58.7	0.9	1.4
Kentucky	55.0	55.0	52.3	0.0	-4.9
Maine, Vermont, New Hampshire	80.9	80.3	80.4	-0.7	-0.6
Maryland, Delaware	66.4	69.2	70.2	4.2	5.8
Massachusetts, Connecticut, Rhode Island	80.6	84.7	84.5	5.1	4.9

(Continued)

TABLE 8. (Continued)

State	Base Case 1995	Option II-2A	Option II-2B	Percent Difference from 1995 Base Case: Option II-2A	Percent Difference from 1995 Base Case: Option II-2B
Michigan	57.7	58.2	57.9	0.9	0.4
Minnesota	54.2	55.1	57.4	1.8	6.0
Missouri	59.6	63.8	65.5	7.0	9.9
Montana	41.1	41.0	41.7	-0.3	1.3
Nevada	48.8	47.0	47.0	-3.7	-3.7
New Mexico	68.2	67.2	64.1	-1.5	-6.1
New York (Downstate), New Jersey	99.3	100.3	100.1	1.0	0.9
New York (Upstate)	53.1	55.3	55.3	4.1	4.1
Ohio	57.8	62.2	80.3	7.6	38.8
Pennsylvania	58.2	60.0	60.4	3.1	3.8
Tennessee	46.9	50.7	53.7	8.1	14.6
Texas	79.4	79.4	79.3	0.0	-0.2
Utah	39.0	44.7	44.7	14.6	14.6
Virginia, District of Columbia	58.7	60.7	65.8	3.4	12.0
Washington, Oregon	35.4	35.4	35.5	0.2	0.3
West Virginia	27.2	46.7	92.0	71.5	238.2
Wisconsin	52.7	57.9	65.2	9.9	23.8
Wyoming	43.0	43.5	43.3	1.0	0.6
National Average	62.0	63.5	65.4	2.5	5.4

SOURCE: Congressional Budget Office.

Tables 9 and 10). Total production from these same states in 1995 could drop even further under SO_2 reduction plans--by as much as 25 percent under an 8 million ton rollback (Option II-1A) and by as much as 39 percent under a 10 million ton reduction (Option II-2A), assuming no restrictions are placed on choice of fuels. If fuel switching is severely limited, future pro-

TABLE 9. COAL PRODUCTION CHANGES AS OF 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of tons)

State	Base Case 1985	Base Case 1995	Option II-1A	Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Alabama	26.6	23.8	25.5	21.4	1.7	-2.4
Arizona	10.3	14.2	13.8	14.2	-0.4	0.0
Colorado	17.0	19.1	20.3	24.5	1.3	5.5
Illinois	62.1	56.4	46.2	48.9	-10.2	-7.4
Indiana	36.6	29.2	24.3	25.3	-4.9	-3.9
Iowa	0.6	1.5	0.5	0.5	-1.0	-1.0
Kansas	1.0	2.5	0.4	1.2	-2.0	-1.3
Kentucky	158.3	208.9	211.6	193.3	2.7	-15.7
Maryland	3.3	2.5	1.6	2.3	-0.9	-0.2
Missouri	5.6	8.1	5.4	5.5	-2.7	-2.6
Montana	32.9	34.0	26.0	41.1	-8.0	7.1
New Mexico	19.5	31.9	31.8	32.2	0.0	0.3
North Dakota	25.9	22.7	22.7	22.4	0.0	-0.3
Ohio	33.3	24.3	4.0	9.8	-20.2	-14.4
Oklahoma	4.5	7.7	7.0	7.0	-0.6	-0.6
Pennsylvania	65.0	82.3	69.4	69.2	-12.9	-13.1
Tennessee	7.1	5.3	6.9	4.8	1.6	-0.6
Texas	45.2	109.4	108.8	98.4	-0.6	-10.9
Utah	13.0	31.6	31.8	31.1	0.2	-0.4
Virginia	44.0	50.6	57.2	58.6	6.6	8.0
Washington	4.2	0.5	0.5	0.5	0.0	0.0
West Virginia	132.1	232.2	261.7	259.2	29.4	27.0
Wyoming	135.2	130.5	151.7	160.3	21.2	29.8
U.S. Total	883.2	1,128.9	1,129.1	1,131.8	0.2	2.9

SOURCE: Congressional Budget Office.

duction would still fall, but by less; expected 1995 levels would be 20 percent lower under the 8 million ton case (Option II-1B) and 23 percent lower under the 10 million ton case (Option II-2B). In contrast, states with large reserves of low-sulfur coal--such as West Virginia, Wyoming, and Colorado--would increase their expected 1995 production over the base case under all SO_2 rollback alternatives.

TABLE 10. COAL PRODUCTION CHANGES AS OF 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of tons)

State	Base Case 1985	Base Case 1995	Option II-2A	Option II-2B	Difference from 1995 Base Case: Option II-2A	Option II-2B
Alabama	26.6	23.8	22.1	20.1	-1.7	-3.7
Arizona	10.3	14.2	13.9	14.2	-0.3	0.0
Colorado	17.0	19.1	23.5	31.9	4.5	12.8
Illinois	62.1	56.4	37.6	47.0	-18.8	-9.4
Indiana	36.6	29.2	19.7	23.5	-9.5	-5.7
Iowa	0.6	1.5	0.5	0.5	-1.0	-1.0
Kansas	1.0	2.5	0.4	1.5	-2.0	-1.0
Kentucky	158.3	208.9	195.9	187.8	-13.0	-21.1
Maryland	3.3	2.5	1.5	2.3	-1.0	-0.2
Missouri	5.6	8.1	5.3	5.4	-2.8	-2.7
Montana	32.9	34.0	26.0	40.5	-8.1	6.5
New Mexico	19.5	31.9	31.9	32.5	0.0	0.7
North Dakota	25.9	22.7	22.7	22.2	0.0	-0.5
Ohio	33.3	24.3	4.0	8.9	-20.2	-15.3
Oklahoma	4.5	7.7	7.0	7.0	-0.6	-0.7
Pennsylvania	65.0	82.3	56.3	68.8	-26.0	-13.5
Tennessee	7.1	5.3	4.9	4.8	-0.4	-0.6
Texas	45.2	109.4	108.8	98.5	-0.6	-10.8
Utah	13.0	31.6	32.8	31.1	1.2	-0.5
Virginia	44.0	50.6	56.0	55.2	5.3	4.6
Washington	4.2	0.5	0.5	0.5	0.0	0.0
West Virginia	132.1	232.2	274.6	228.2	42.4	-4.0
Wyoming	135.2	130.5	191.2	205.2	60.7	74.7
U.S. Total	883.2	1,128.9	1,137.1	1,137.6	8.1	8.6

SOURCE: Congressional Budget Office.

Under either rollback scheme--but especially when fuel choice is not restricted--demand would increase for low-sulfur coal at the expense of high-sulfur coal. (In this study, low-sulfur coal is defined as producing fewer than 1.2 pounds of SO_2 per million Btus, and high-sulfur coal as more than 5.0 pounds of SO_2 per million Btus.) Under current regulations, low-sulfur coal production in 1995 is estimated to be 368 million tons, while high-sulfur coal production is estimated at 198 million tons. Under an 8 million ton reduction scenario without any fuel restrictions (Option II-1A), low-sulfur coal production could reach 485 million tons by 1995, and high-sulfur coal production could fall to 146 million tons. Under a similar 10 million ton program (Option II-2A), low-sulfur coal production could jump to 557 million tons in 1995, while high sulfur coal production could plummet to 118 million tons. The "winners" from such an effect would be the low-sulfur coal producing areas of the East (mostly West Virginia) and the western coal producing states in general. The "losers," of course, would be the midwestern states and Pennsylvania, which produce an abundance of high-sulfur coal.

Effect on Coal Market Employment

From the actual and estimated coal production figures described above, CBO estimated the effects of a SO_2 rollback scheme on coal mining jobs, using labor productivity (average tons of coal produced per miner per year) available for each region of the country. 14/ Two types of job measures are important: changes estimated from current actual job holders, and changes estimated from expected 1995 job slots under current law.

Changes from 1985 Employment. The CBO estimates that from 1985 through 1995, direct coal mining employment should grow nationally from about 208,000 to just over 275,000. Enactment of a SO_2 rollback policy (see Tables 11 and 12) might lower these national estimates somewhat, as demand inevitably increased for low-sulfur western coal, which is mined principally by highly productive surface methods that require less labor. Of more concern, however, are the regional shifts that might occur in the coal mining job market.

---

14. These projections of employment are based on productivity measures contained in Department of Energy, Energy Information Agency, *Coal Production 1983*. These values include all employees engaged in production, preparation, processing, development, maintenance, repair, and shop or yard work at mining operations. They exclude office workers, but include mining operations management and all technical and engineering personnel. Productivity was assumed to remain constant over the period of analysis.

TABLE 11. COAL MINING EMPLOYMENT CHANGES AS OF 1995 UNDER 8 MILLION TON SO_2 ROLLBACK, BY COAL-PRODUCING STATE

State	Number of Jobs: Base Case 1985	Number of Jobs: Base Case 1995	Number of Jobs: Option II-1A	Number of Jobs: Option II-1B	Difference from 1985: Base Case 1995	Difference from 1985: Option II-1A	Difference from 1985: Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Alabama	9,077	8,124	8,714	7,318	-953	-363	-1,759	590	-805
Arizona	855	1,177	1,141	1,177	322	286	322	-36	0
Colorado	2,927	3,288	3,510	4,235	360	583	1,307	223	947
Illinois	16,228	14,733	12,068	12,787	-1,495	-4,160	-3,441	-2,665	-1,946
Indiana	6,694	5,342	4,446	4,623	-1,352	-2,248	-2,071	-896	-719
Iowa	136	344	110	110	208	-27	-26	-234	-234
Kansas	306	753	129	353	447	-177	47	-624	-399
Kentucky	47,753	63,014	63,818	58,291	15,261	16,065	10,538	804	-4,723
Maryland	923	695	447	649	-228	-476	-274	-248	-46
Missouri	1,348	1,948	1,297	1,323	600	-51	-26	-651	-625
Montana	1,209	1,251	956	1,513	42	-253	303	-295	261
New Mexico	1,741	2,846	2,844	2,876	1,104	1,103	1,134	-2	30
North Dakota	1,570	1,375	1,374	1,359	-195	-196	-211	-1	-15
Ohio	9,797	7,136	1,183	2,895	-2,662	-8,614	-6,902	-5,953	-4,241
Oklahoma	1,377	2,344	2,146	2,158	967	770	781	-197	-186
Pennsylvania	23,134	29,299	24,701	24,624	6,165	1,567	1,490	-4,598	-4,675
Tennessee	2,685	2,010	2,616	1,796	-675	-69	-889	606	-214
Texas	2,851	6,890	6,855	6,201	4,039	4,004	3,350	-35	-689
Utah	3,283	7,978	8,040	7,867	4,695	4,757	4,583	62	-111
Virginia	16,803	19,339	21,852	22,387	2,536	5,049	5,584	2,513	3,048
Washington	426	48	48	48	-378	-378	-378	0	0
West Virginia	50,893	89,473	100,811	99,864	38,580	49,918	48,971	11,337	10,391
Wyoming	5,975	5,768	6,706	7,086	-207	731	1,111	938	1,318
U.S. Total	207,992	275,172	275,812	271,539	67,181	67,820	63,547	640	-3,634

SOURCE: Congressional Budget Office.

TABLE 12. COAL MINING EMPLOYMENT CHANGES AS OF 1995 UNDER 10 MILLION TON SO_2 ROLLBACK, BY COAL-PRODUCING STATE

	Number of Jobs				Difference from 1985			Difference from 1995 Base Case	
State	Base Case 1985	Base Case 1995	Option II-2A	Option II-2B	Base Case 1995	Option II-2A	Option II-2B	Option II-2A	Option II-2B
Alabama	9,077	8,124	7,543	6,862	-953	-1,534	-2,215	-581	-1,262
Arizona	855	1,177	1,155	1,177	322	300	322	-22	0
Colorado	2,927	3,288	4,062	5,498	360	1,135	2,571	775	2,210
Illinois	16,228	14,733	9,823	12,273	-1,495	-6,405	-3,955	-4,910	-2,460
Indiana	6,694	5,342	3,611	4,294	-1,352	-3,083	-2,401	-1,732	-1,049
Iowa	136	344	110	110	208	-27	-26	-234	-234
Kansas	306	753	129	462	447	-177	156	-624	-291
Kentucky	47,753	63,014	59,098	56,649	15,261	11,345	8,897	-3,916	-6,365
Maryland	923	695	417	649	-228	-505	-274	-278	-46
Missouri	1,348	1,948	1,276	1,297	600	-72	-51	-672	-651
Montana	1,209	1,251	955	1,490	42	-254	281	-296	238
New Mexico	1,741	2,846	2,846	2,906	1,104	1,104	1,164	0	60
North Dakota	1,570	1,375	1,374	1,345	-195	-196	-225	-1	-29
Ohio	9,797	7,136	1,183	2,633	-2,662	-8,614	-7,164	-5,953	-4,503
Oklahoma	1,377	2,344	2,146	2,131	967	770	754	-197	-213
Pennsylvania	23,134	29,299	20,042	24,482	6,165	-3,092	1,349	-9,257	-4,816
Tennessee	2,685	2,010	1,859	1,796	-675	-826	-889	-151	-214
Texas	2,851	6,890	6,854	6,208	4,039	4,004	3,357	-36	-683
Utah	3,283	7,978	8,282	7,862	4,695	4,998	4,579	304	-116
Virginia	16,803	19,339	21,375	21,076	2,536	4,572	4,273	2,036	1,738
Washington	426	48	48	48	-378	-378	-378	0	0
West Virginia	50,893	89,473	105,792	87,936	38,580	54,899	37,043	16,319	-1,537
Wyoming	5,975	5,768	8,451	9,072	-207	2,476	3,097	2,683	3,304
U.S. Total	207,992	275,172	268,431	258,255	67,181	60,439	50,263	-6,741	-16,917

SOURCE: Congressional Budget Office.

In terms of potential job losses, the high-sulfur coal states of Illinois, Indiana, Ohio, and Pennsylvania would be particularly sensitive to the effects of a SO_2 rollback. Under current law, these states might employ about the same number of miners in 1995 as in 1985. Under an 8 million ton SO_2 rollback, however, anywhere from 11,000 to 13,500 current job slots in these four states could be lost (Options II-1B and II-1A, respectively). Similarly, a 10 million ton SO_2 rollback could eliminate from 12,200 to 21,200 current job slots (Options II-2B and II-2A, respectively). Of course, the number of miners actually employed in 1985 who would lose their jobs by 1995 because of an acid rain policy would be lower because of natural attrition; perhaps 10.5 percent of miners currently employed might simply retire by 1995.[15] Thus, of the miners employed in the four-state region in 1985, as many as 5,900 could be expected to retire by 1995, reducing losses among current job holders accordingly. For example, under a 10 million ton rollback, between 6,300 and 15,300 currently employed miners could lose their jobs by 1995 (Options II-2B and II-2A, respectively).

In contrast to high-sulfur coal states, some states producing low-sulfur coal could prosper from enactment of a SO_2 rollback plan. In the West, Wyoming and Colorado have the greatest potential for higher overall coal production--and hence, employment--under a SO_2 reduction plan, although restrictions on fuel switching could temper this trend (see Tables 11 and 12). Moreover, while production could rise significantly in these states (see Tables 9 and 10), the effect on mining employment also would be dampened by the high productivity of the process. This does not hold, however, for the East's great low-sulfur coal resource--West Virginia. West Virginia's coal mining employment levels could roughly double by 1995 under either an 8 million ton or 10 million ton SO_2 rollback that allowed unlimited fuel switching (Options II-1A and II-2A, respectively). Such employment increases from current levels would be aided not only by increased production but also by the labor-intensive nature of Appalachian coal mining.

---

15. Estimates of job attrition in the coal mining industry are quite difficult to calculate, a situation that is reflected by the sparsity of such estimates in the literature. One notable exception is a monograph by Joseph P. Brennan, President of the Bituminous Coal Operator's Association, "Coal Industry Labor Issues," *Proceedings: Fuel Supply Seminars* (Electric Power Research Institute, March 1983). The 10.5 percent retirement factor over the 1985-1995 period is based on this publication's reported age profile for United Mine Workers in 1980. Assuming the same profile applies to all miners (including nonunion miners) in 1985, 10.5 percent of the worker population would reach retirement age (65) in 1995. Such estimates, while illustrative, do not even consider early retirement, disability, or natural job turnover and should thus be assumed to represent a lower bound.

Changes from Expected 1995 Levels. Although employment changes from 1985 through 1995 provide insight into how many people in today's workforce might lose (or gain) employment because of future policies, they reveal little about how one policy might change the anticipated employment levels (job slots) compared with the effects of a different policy. Because comparing the future job slots of different policies avoids the difficulties of estimating job attrition or the potential errors of comparing actual levels (those measured today) with predicted ones, the remainder of this report concentrates on 1995 job levels. Such comparisons can overestimate job losses and underestimate the potential gains of today's workforce, however, because they do not consider attrition.

For the predominantly high-sulfur coal-producing states of Illinois, Indiana, Ohio and Pennsylvania, job slots are expected to rise to 56,500 in 1995 (or 660 above the 1985 level). Under a rollback scheme that does not prevent fuel switching, job losses from forecasted levels could be significant. An 8 million ton SO_2 reduction could lower expected 1995 employment in these states by 14,100 (Option II-1A), while a 10 million ton reduction could lower them by 21,900 (Option II-2A). Restricting the amount of allowed fuel switching would provide little additional job protection under a 8 million ton SO_2 reduction (jobs would still fall by 11,600 in 1995 under Option II-1B), but would retard losses under a 10 million ton rollback program (jobs slots would fall by 12,800 in 1995 under Option II-2B).

From a national perspective, more jobs might be lost if an attempt were made to preserve current coal market supply and demand patterns (the no fuel switching case) than if fuel switching were allowed (see Tables 11 and 12). If current coal patterns were preserved, the job losses that did occur in eastern and midwestern states would be only partially offset by increased western coal consumption. Yet, from the Midwest's perspective, more jobs would be saved if fuel switching were restricted than if it were not, because midwestern high-sulfur coal mines would still meet a large portion of coal demand in that area.

CHAPTER III

ALLOCATING EMISSION REDUCTION COSTS THROUGH TAXES COLLECTED ON ELECTRICITY PRODUCTION

During the 98th Congress, several proposals to reduce sulfur dioxide emissions were introduced that would provide substantial subsidies for the installation of scrubbers on the affected electricity power plants. The subsidies would be funded by a temporary tax on electricity production, and the proceeds distributed through a federal trust fund. 1/ The purpose of these proposals is twofold: (1) to lower the cost of scrubbers and, thus, to encourage their use by the utilities most affected by more stringent emission regulations--such as those in the Midwest and parts of the mid-Atlantic region; and (2) to preserve high-sulfur coal mining jobs, while spreading program costs more evenly throughout the country. This chapter explores several tax and subsidy alternatives to rollback sulfur dioxide emissions by 8 million tons and 10 million tons, and compares them with the basic polluter pays options described in Chapter II.

In contrast with the simple polluter pays approach which establishes emission reductions but does not stipulate or encourage any particular control method, a generation tax and scrubber subsidy option would cost more to lower emissions by the same amount. Recalling the results of Chapter II, the total program cost of an 8 million ton SO_2 reduction (based on 1980 emissions) would be roughly $20 billion (in discounted 1985 dollars), assuming no restrictions on the choice of control method or coal used (Option II-1A). Under the same assumptions, the total program cost of a 10 million ton reduction would be about $35 billion (Option II-2A). (Options II-1A and II-2A are used for comparative purposes throughout this chapter. For easy reference, the options are described in the glossary at the end of this report.) In comparison, an 8 million ton SO_2 reduction program that both provides a 90 percent capital and 50 percent operation and maintenance (O&M) subsidy for scrubber use and collects funds through a self-financing temporary 1 mill per kilowatt-hour (mill/kwh) tax on fossil-fuel electricity generation

1. For the purposes of this study, the terms "fee" and "tax" simply refer to the revenue collection mechanism; they do not reflect the way these terms are used in the federal budget for accounting purposes. In the federal budget, taxes are classed as revenue, while fees are defined as offsetting receipts. For further information, see Government Accounting Office, *A Glossary of Terms Used in the Federal Budget Process* (March 1984).

would cost about $30 billion (in discounted 1985 dollars). A comparable 10 million ton program would cost about $42 billion. In both cases, the higher costs arise chiefly from the purchase and use of more scrubbers as a result of the subsidy program. (This study does not consider the potential efficiency losses that could occur from the imposition of generation taxes.)

While the generation tax and subsidy programs would be more costly than the polluter pays approach, they would also be more effective in limiting the loss of mining jobs in the key high-sulfur coal states because they encourage the use of scrubbers rather than switching to low-sulfur coal. For example, coal mining employment in Illinois, Indiana, Ohio, and Pennsylvania is estimated to be 56,500 in 1995 under current law. In contrast, an 8 million ton SO_2 emission rollback with no restrictions on fuel switching could lower 1995 employment to 42,400 in these states, and a comparable 10 million ton reduction program could reduce it to 34,700. A rollback program with generation taxes and scrubber capital and operating subsidies could lessen job losses in high-sulfur coal mining. Employment in the four states would fall from 56,500 in 1995 to only 52,000 under an 8 million ton program, and to 45,300 under a 10 million ton program.

Finally, the most expensive option was found to be a program that required the top 50 SO_2 "emitters" to install scrubbers achieving an initial SO_2 reduction of about 7 million tons. States would then have to meet a total reduction of 10 million tons of SO_2 from 1980 levels by instituting additional control measures. Coupled with a 0.75 mill/kwh fee on electricity production, this option would cost roughly $49 billion (in discounted 1985 dollars), compared with $35 billion (in discounted 1985 dollars) under the polluter pays approach of Option II-2A. This option could be the most effective, however, in preventing the loss of future high-sulfur coal jobs, holding employment levels in Illinois, Indiana, Ohio, and Pennsylvania to 47,600 in 1995, higher than under any of the other subsidy schemes with a 10 million ton SO_2 reduction and significantly above the 34,700 expected under Option II-2A.

RATIONALE BEHIND SUBSIDIZING CONTROL COSTS THROUGH AN ELECTRICITY TAX

Chapter II described the effect of sulfur dioxide rollback programs that did not involve any fees or subsidies, but only required each state to meet certain emission reduction targets. Two key findings arose from the analysis in that chapter. First, significant costs for pollution control would be concentrated in the Midwest, Pennsylvania, and West Virginia. Second, high-sulfur coal production could significantly fall from anticipated levels, principally affecting jobs in the Midwest and Pennsylvania, as utilities switched to low-sulfur coal to meet emission targets. (Employment might increase in West Virginia, however, because of the greater demand for its low-sulfur coal.) The possibility of these shifts has prompted a search for ways to redistribute costs and coal-market effects, to lessen the burden on the Midwest and parts of the East (especially Pennsylvania).

A system of fees and subsidies to abate acid rain was popular in legislation proposed during the 98th Congress. 2/ Several common elements characterized these proposals. Most would require a total SO_2 reduction of ten million tons from 1980 levels. As a cornerstone of these plans, the 50 power plants with the highest SO_2 emissions (based on 1980 levels) would be required to install scrubbers, which would reduce this pollutant by roughly 7 million tons. These plans called for the states to achieve an additional 3 million ton reduction using the excess emissions formula, described on page 14 in Chapter II.

Affected plants that installed scrubbers (either by choice or by law), would receive a subsidy up to 90 percent of the scrubber's capital costs. Some proposals would also fund a portion of annual scrubber operation and maintenance costs. To raise funds for the subsidies, the typical approach would tax electricity produced by plants fired by fossil fuels. Usually, nuclear power and sometimes hydroelectric power were excluded. 3/ The tax would begin immediately upon passage of the legislation at a level ranging from 1 to 3 mills/kwh (sometimes indexed for inflation) and would con-

---

2. Several bills that would allocate the cost of acid rain controls through a generation tax and emissions control subsidy program were introduced in the 98th Congress. These include H.R. 5794 (Rep. Eckart), H.R. 5970 (Rep. Vento), H.R. 4906 (Rep. Rinaldo), H.R. 4404 (D'Amours), and H.R. 3400 (Rep. Sikorski), which was identical to H.R. 5314 (Rep. Waxman). All bills called for a 10 million ton reduction in SO_2 emissions from 1980 levels within 10 years of enactment, affecting the contiguous 48 states. The bulk of emission reductions was to be accomplished through scrubber retrofits on the top 50 SO_2 emitters whose emission rates were also above 3.0 pounds SO_2 per million Btus. The electricity fee rates ranged from 1 to 1.5 mill/kwh and were indexed for inflation in all cases except H.R. 3400 and H. R. 5314. Nuclear-generated electricity was exempted from the tax in all proposals, and hydro power also was exempted in H.R. 4906 and H.R. 4404. H.R. 5970 provided up to a 50 percent capital credit for retrofitted scrubbers, but H.R. 3400 and H.R. 5314 provided a 90 percent credit. H.R. 5794 includes an O&M subsidy of 50 percent the first year and 45 percent the second.

3. The rationale behind these exclusions, though not always stated, was that hydro power already inherently produced little pollution and that nuclear generation already was taxed (at 1 mill/kwh) to finance the federal radioactive waste disposal program. See Congressional Budget Office, *Nuclear Waste Disposal: Achieving Adequate Financing*(August 1984).

tinue for 10 years to 1995, by which time emission reduction goals were to be achieved. Capital payments could begin as early as 1990 and would continue until all scrubbers were constructed. Finally, most proposed legislation placed revenues in an interest-bearing government trust fund. Some bills would have the Treasury keep any excess funds at the end of the program, while others would return them to the consumers according to each state's contribution.

The advantages of such proposals are that they would be effective in raising large sums of money through modest and relatively equal increases in regional electricity prices. The subsidy schemes also would promote greater scrubber use and, thus, could help preserve future demand for high-sulfur coal. Opponents, however, believe that such schemes would tax utilities in western states unfairly since they are not responsible for the acid rain problem in the East, the area that such programs are designed to aid. Moreover, while those power plants that possibly contribute most to the problem (the high emitting plants of the Midwest) would be taxed at the same rate as other power plants, they would receive the most aid. All these concerns have foundation and lie at the heart of selecting the most appropriate cost allocation scheme. [4]

ELECTRICITY TAX AND SUBSIDY OPTIONS

This section examines five different emission reduction options using taxes and subsidies and covering two levels of sulfur dioxide reduction: 8 million tons and 10 million tons, both measured from 1980 levels. Table 13 summarizes the options. Each would be accompanied by an electricity fee to cover all subsidy requirements of the program. Collection would begin in 1986 and end in 1995, with revenues deposited in an interest-bearing trust fund. Subsidies would be designed to pay for most of the annual cost of capital over the useful life of the installed scrubbers, which is estimated as 20 years for retrofits. Payments from the fund would begin in 1991--the year construction is assumed to begin--and would end in 2015--the last year of the useful life of those scrubbers whose installation is assumed to be completed in 1995.

Two types of subsidies are examined. The first would pay for 90 percent of the annual capital cost of scrubber installation (including interest

4. For additional discussion of the rationale behind and administrative issues surrounding such allocation schemes, see Rob Brenner and Milton Russell, "Allocating the Costs of Acid Rain Controls," in *Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing*, Public Utility Papers (Michigan State University Press, 1984).

charges) for plants choosing to retrofit scrubbers under each SO_2 reduction program (Options III-1A and III-2A for 8 million ton and 10 million ton rollbacks, respectively). Payments from the trust fund would continue over the expected useful life of the scrubber. The second type of subsidy not only would cover 90 percent of capital retrofit cost but also would pay for 50 percent of annual O&M costs over the same 20-year period (Options III-1B and III-2B for 8 million ton and 10 million ton rollbacks, respectively). The rationale for the additional subsidy for O&M is to encourage greater scrubber use than might be expected if only capital costs were subsidized.

TABLE 13. EMISSION REDUCTION OPTIONS USING TAXES AND SUBSIDIES

Policy Option	Emission Reduction from 1980 Levels	Tax System	Subsidy System for Retrofit Scrubbers
Option III-1A	8 million tons, excess emissions formula	0.5 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital
Option III-1B	8 million tons, excess emissions formula	1 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital, 50 percent annual cost of O&M
Option III-2A	10 million tons, excess emissions formula	0.5 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital
Option III-2B	10 million tons, excess emissions formula	1 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital, 50 percent annual cost of O&M
Option III-2C	10 million ton--7 million ton from top 50 emitters; remainder from utilities in states according to excess emissions formula	0.75 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital, including retrofitting the top 50 emitting plants as well as others needed to meet reduction targets.

SOURCE: Congressional Budget Office.

The first four emission reduction schemes examined in this chapter base state-by-state emission control targets on the excess emissions formula. An exception--the proposal to retrofit scrubbers on the top 50 SO_2 emitting power plants--is examined in Option III-2C. This option is similar to the bills submitted by Representatives Waxman and Sikorski during the 98th Congress, although the version contained here has several variations. In particular, the CBO version differs by requiring all emission reductions to occur by 1995 (instead of some in 1992 as required by H.R. 5314), and by setting a fee of 0.75 mill/kwh in constant dollars, compared with the 1 mill/kwh fee in nominal dollars contained in the original proposal.

Effect on Utility Emissions

Option III-1A would achieve a 7.3 million ton emission reduction from 1995 projected levels (after accounting for emissions growth from the baseline year of 1980); similarly, Options III-2A, III-2B, and III-2C would lower expected 1995 emissions by 9.3 million tons. These results are very similar to the 8 and 10 million ton SO_2 reductions achieved under the polluter pays options of Chapter II (see Table 3).

Most of the required emission reductions would occur in the Midwest, Pennsylvania, and West Virginia--as they would under the options in Chapter II. The emission reduction pattern resulting from installing scrubbers on the top 50 emitters throughout the United States (Option III-2C) also is similar to those based on the excess emissions formula (Options III-2A and III-2B). This suggests that the excess emissions formula--which sets state-wide emission limits--is largely influenced by high-emitting power plants. Unlike the "top 50" approach, however, which sets limits for individual plants, the excess emissions formula allows greater flexibility in compliance.

Total Program Costs of Each Option

Total program costs for the tax and subsidy options would be higher and the cost-effectiveness inferior compared with the simple polluter pays approach. Option II-1A would cost about $20 billion with SO_2 reductions obtained at a price of $270 per ton. In comparison, the cheapest generation tax and subsidy scheme that could achieve a comparable reduction (Option III-1A) would cost about $22 billion, or $291 per ton of SO_2 abated from 1995 levels under currrent policy (see Table 14). Similarly, Option II-2A would cost roughly $35 billion, or $360 per ton of SO_2 abated. The cheapest tax and subsidy scheme with a comparable 10 million ton rollback

TABLE 14. COMPARISON OF TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF VARIOUS OPTIONS UNDER TWO ROLLBACK PROGRAMS

	8 Million Ton SO_2 Reduction		
	Polluter Pays, No Fuel Restrictions (Option II-1A)	90 Percent Capital Subsidy (Option III-1A)	90 Percent Capital, 50 Percent O&M Subsidies (Option III-1B)
Total Program Cost (In billions of discounted 1985 dollars) a/	20.4	22.3	30.0
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	270	291	389

	10 Million Ton SO_2 Reduction			
	Polluter Pays, No Fuel Restrictions (Option II-2A)	90 Percent Capital Subsidy (Option III-2A)	90 Percent Capital 50 Percent O&M Subsidies (Option III-2B)	Top 50 Plant SO_2 Reduction (Option III-2C)
Total Program Cost (In billions of discounted 1985 dollars) a/	34.5	35.5	41.5	49.0
Cost-effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	360	369	431	509

SOURCE: Congressional Budget Office.

a. Reflects net present value of sum of annual utility expenditures--including the subsidized portions but not including taxes--incurred between 1986 and 2015, discounted to 1985 dollars. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reductions measured over the 1986-2015 period.

(Option III-2A) would be more expensive, costing $36 billion overall and $369 for each ton of SO_2 reduced. (All costs are in discounted 1985 dollars.)

Because the options presented in this chapter involve taxes and subsidies, the definitions of cost measures change somewhat from those given in Chapter II. For example, in a program with tax and subsidies, discounted program costs represent all the expenses incurred by the utilities (including taxes and subsidies), plus the costs of running the trust fund, minus the balance remaining at the end of the fund's life (see box). In addition, this study assumes that no additional costs would be incurred by the transfer of funds from the private sector into a government trust fund, as long as any surplusses were eventually returned to the contributors. 5/

Annual Net Cost to Utilities. Compared with current policy, the additional 1995 net annual costs of an 8 million ton emission reduction program (including generation fees but subtracting subsidies) would range between $3.0 billion (Option III-1A) and $3.6 billion (Option III-1B). Compared with the polluter pays approach of Chapter II (Option II-A), however, Option III-1A would cost $1.1 billion more per year in 1995 and Option III-1B, $1.7 billion more. These higher costs would arise from the electricity tax and the subsidy system, which encourages scrubbing--a more expensive method of emission abatement than fuel switching (see Table 15).

For a 10 million ton reduction program--again compared with current policy in 1995--the utilities' net annual costs, including fees and subsidies would range from $4.3 billion (Option III-2A) to as high as $5.4 billion (Option III-2C). In contrast with Option II-2A, the net costs in 1995 of the fee and subsidy programs would range from $873 million to $2.1 billion higher (see Table 16).

The different subsidy schemes influence utilities' choice of control strategy between installing scrubbers or switching to low-sulfur coal. Under the 8 million ton reduction option, the total amount spent on scrubbers rises dramatically--nearly tripling from $3.8 billion to over $11.1 billion--when the subsidy is increased from 90 percent on capital investment (Option III-1A) to both 90 percent on capital and 50 percent for O&M (Option III-1B). When the subsidy under the 10 million ton option is similarly increased, total scrubber investment rises by more than 60 percent, from $7.1 billion under Option III-2A to $11.9 billion under Option III-2B. Yet,

5. The real discount rate used in calculating the earnings of the trust fund and determining the net present value of the program costs were the same--3.7 percent. The rate represents the average cost the government pays to finance credit.